Energy+Environmental Economics

Overview of Public Tool to Evaluate Successor Tariff/Contract Options

December 16th, 2014

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Roadmap of Today's Meeting

- Today's meeting provides explanation of how we plan to address party comments and reply comments in the Public Tool
- Our agenda follows the order of the ALJ's ruling seeking post-Workshop comments

AES/vm2 9/5/2014

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BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Develop a Successor to Existing Net Energy Metering Tariffs Pursuant to Public Utilities Code Section 2827.1, and to Address Other Issues Related to Net Energy Metering.	Rulemaking 14-07-002 (Filed July 10, 2014)

ADMINISTRATIVE LAW JUDGE'S RULING SEEKING
POST-WORKSHOP COMMENTS

Overview of Proposed Approach
Questions 1-2

Modeling Approach
Questions 3-9

Data Sources
Questions 10-11

Public Tool
Questions 12-20

Pricing Mechanisms and Rate Design
Questions 21 - 27

Other Issues
Question 29

Overview of Approach

9:15 am – 10:00 am

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Overview of this Section

- **This section of today's workshop provides an overview of and context for how we propose to address party comments in the Public Tool**
  - Timeline
  - Approach to Tool Development
  - Overview of functionality and results
  - Summary of party responses incorporated in the public tool
  - Questions on this section of workshop

Overall Project Scope

- **Develop a Public Tool that enables parties to efficiently model the impact of various rate designs and input assumptions, run custom scenarios, and model user-defined options for a successor tariff or contract that:**
  - Balances the competing goals in AB 327 (Perea, 2013) for all customers
  - Supports the development of an alternative tariff/contract for 'disadvantaged communities,' if appropriate
  - Encourages the sustainability of renewable distributed generation (DER) and support CPUC policies and goals like efficiency, storage, etc.
  - Supports the adoption of one or more successor contracts/tariffs by December 31, 2015

Party Feedback Has Shaped Development of Public Tool

Workshop: AB 327 tariff & contract options (April 2014)

ED staff's request for informal post-workshop comments (May 2014)

Workshop: Public Tool proposed approach (Aug. 2014)

ALJ Ruling Seeking Post-Workshop Comments (Sept 2014)

Integration of party comments into revised Public Tool proposal

ALJ Ruling adopting specifications for further development of the Public Tool (Dec. 2014)

ELCC and DG adoption webinar (Dec. 2014)

Workshop Addressing Final Public Tool Proposal (TODAY)

Preliminary Schedule for the Public Tool

- **Workshop: Overview of the final proposed approach, functionality, and user interface of the Public Tool (Today)**
- **’Draft’ version of the Public Tool released, including User Guide (Late January 2015)**
  - Workshop: Discuss, and provide a tutorial on how to use, the draft version of the Public Tool (February 2015)
- **Discuss proposals for 'Disadvantaged Communities,' if appropriate (Late February 2015)**
- **‘Final’ version of the Public Tool released (March/early April 2015)**
  - Workshop: Discuss any changes made from the draft version of the Public Tool (March/early April 2015)

Further information related to the development of the Public Tool is available on the Commission’s webpage: http://www.cpuc.ca.gov/PUC/energy/DistGen/NEMWorkShop04232014.htm

Role of the Public Tool

- **The Public Tool is being developed for several reasons:**
  - To provide a common “language” to talk about all specific proposals and ideas
  - To provide an equal opportunity for all parties to analyze and test their proposals and ideas in meeting the potential scope of requirements set forth in AB 327, without favoring a single approach
  - To provide auditability and vetting of the underlying calculations and inputs by parties
- **The Public Tool is not designed to pick a “best” answer**

Summary of Approach

+ **Tool gives users the ability to change electric rate designs by rate class**
+ **Model calculates associated adoptions and output metrics**
+ **Flexible inputs allow advanced users to modify a wide range of assumptions**
  - Key policy drivers
  - DER system costs
  - Utility costs

High-Level Response to Comments Received on Proposed Approach

- Majority of party comments have been incorporated into the Public Tool
- Open Excel model, with extensive flexibility for users to alter input assumptions
- Team will focus on best available public data for default assumptions and inputs
  - Users will have the ability to change most of the input assumptions

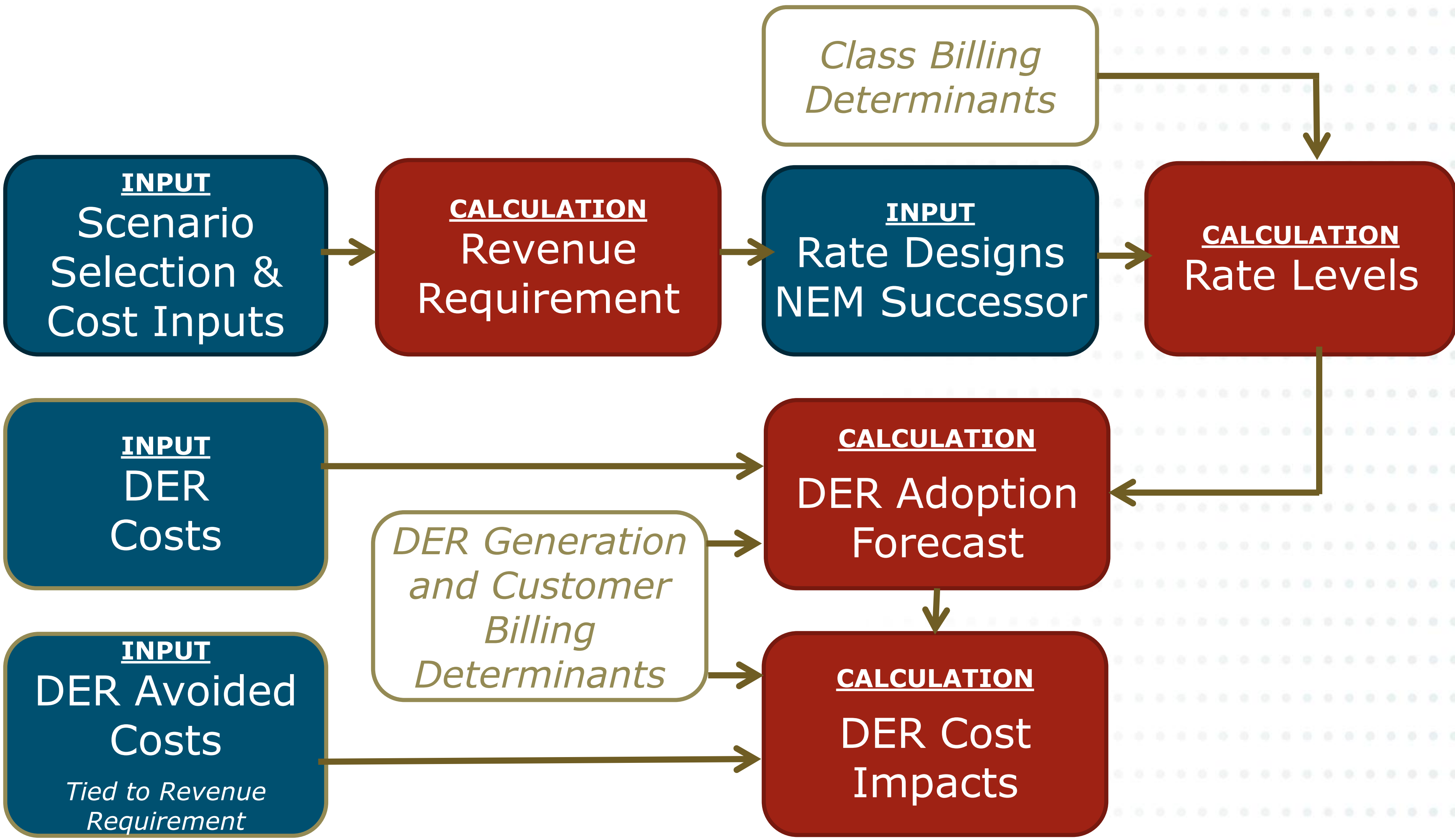
Goals for Public Tool Development

+ **Develop the Public Tool through a transparent, iterative process, incorporating as much of the desired functionality as possible**
+ **Model each California IOU separately**
+ **Estimate costs-benefits from multiple perspectives, while keeping the model user-friendly**
+ **Model DER adoptions by utility customer class and utility**
  - Bundled utility customers
+ **"Live" model calculations (vs. hardcoded values)**
  - Under the original approach, we planned to populate the Public Tool with results from LBNL's Finder Model. This approach would have resulted in limited transparency of calculations.
  - Under the current proposal, we will not use the FINDER model. The Excel Public Tool provides full functionality with full transparency.

Implications of this Approach

- **Two Excel models**
  - One holds billing determinant data for participants
  - One holds Public Tool calculations
- **Two Public Tool interfaces address the increased complexity our approach creates**
  - Basic
    - Users drive model via select inputs
    - Balance of inputs are default values
  - Advanced
    - Allows users to modify all active assumptions

Public Tool Overview



Explanation of Topics We Propose to Not Include in Public Tool

- **E3 has made every effort to accommodate all party requests in the Public Tool**
- **There are, however, some remaining issues that we are unable to accommodate due to**
  - Data Unavailability
  - Regulatory Issues
  - Tool addresses the issue in an alternative way
- **These topics are described in detail in relevant sections throughout the presentation**
- **ALJ ruling issued 12/12/2014 lists the topics not included**

Questions

Modeling Approach
10:00 am – 11:15 am

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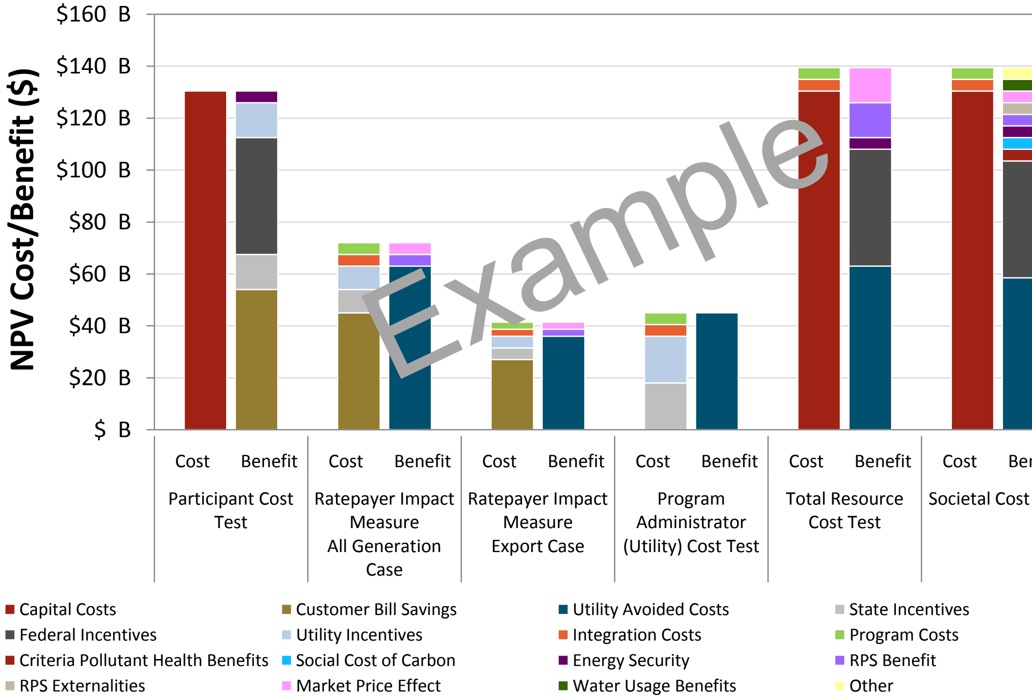
Agenda for Modeling Approach Section

+ Evaluation Metrics
+ Avoided Costs
+ Utility Costs
+ DER System Costs
+ Q & A

Evaluation Metrics

Evaluation Metrics: Cost Impacts of DER

- **Cost impacts of DER will be evaluated using the following standard practice manual cost tests**
  - Participant Cost Test
  - Ratepayer Impact Measure
    - Using all DER generation
  - Ratepayer Impact Measure
    - Using only exported DER generation
  - Program Administrator Cost Test
  - Total Resource Cost Test
  - Societal Cost Test



- **Each cost test will be calculated on a levelized ($/kWh), annualized ($/yr), and absolute (NPV $) basis**
- **Total benefits and costs for each test will be shown by component**
- **The net benefit (cost) & benefit-cost ratio will also be shown by cost test**

Five Cost Test Results

- ***Participant Cost Test (PCT)*****:** Analyzes the financial proposition of purchasing and installing a DER system from a program participant's perspective.
- ***Ratepayer Impact Measure (RIM)*****:** Measures the impact of the DER compensation program on average rates (i.e., the impact on non-participating ratepayers). This is calculated from an all-generation perspective and an export-only perspective.
- ***Program Administrator Cost Test (PAC) or Utility Cost Test (UCT):*** Calculates cost-effectiveness based on the average bill change of all ratepayers (participants and non-participants).
- ***Total Resource Cost Test (TRC):*** Captures the total direct monetary program impact on all residents of the state of California, including participants, non-participants, and utility administrators. Does not include cost shifts between parties within California.
- ***Societal Cost Test (SCT):*** aims to quantify the total program impact on California when externalities are included.

Cost Test Overview

	PCT	RIM	PAC / UCT	TRC	SCT
DER System costs	Cost			Cost	Cost
Utility integration and interconnection cost		Cost	Cost	Cost	Cost
Utility administration cost		Cost	Cost	Cost	Cost
Utility avoided cost		Benefit	Benefit	Benefit	Benefit
Customer bill savings (Utility revenue loss)	Benefit	Cost			
Utility incentives	Benefit	Cost	Cost		
State tax credits/benefits	Benefit				
Federal tax credits/benefits	Benefit			Benefit	Benefit
Other societal benefits					Benefit

Societal Cost Test

+ **Users may input their own avoided cost values for societal cost test calculation**
  - Avoided societal cost of carbon
  - Health benefits
  - Improved energy security
  - Reduced RPS externalities
  - Other

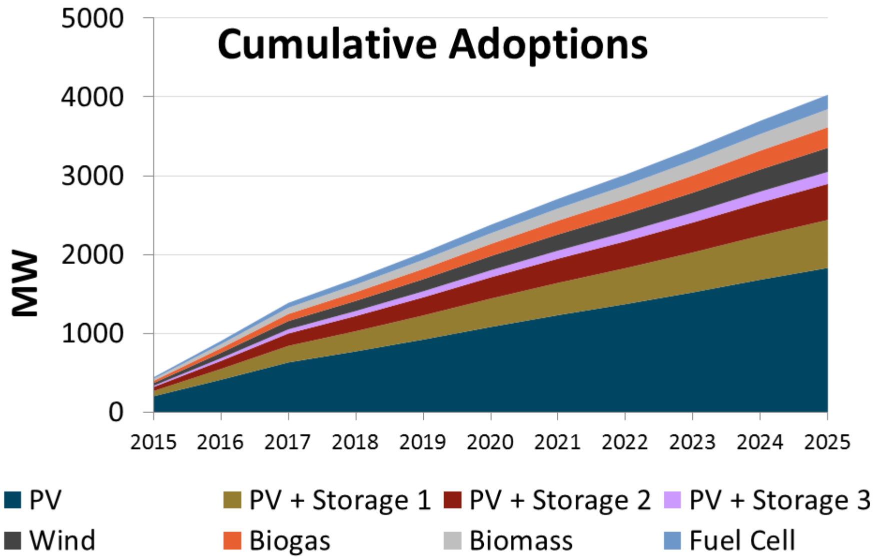
All Generation vs. Export Only

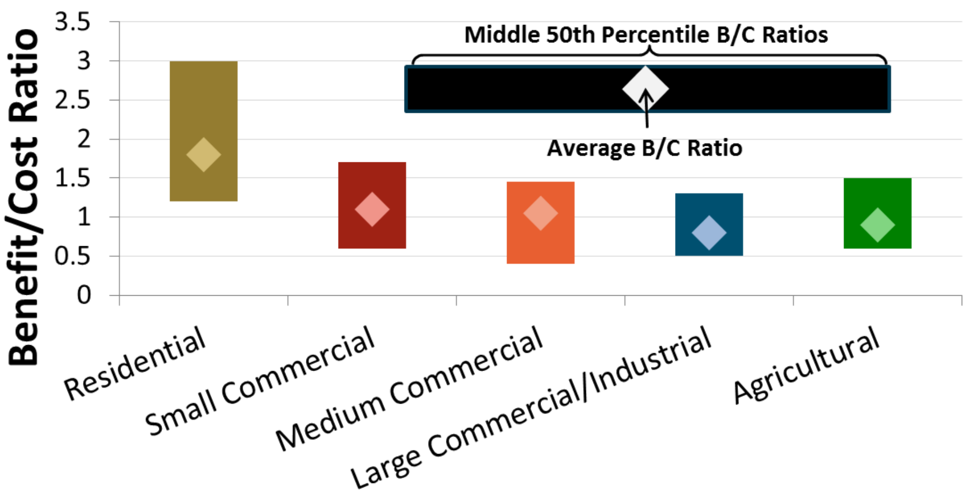
- **The Public Tool outputs the results of the RIM test with two generation definitions:**
  - All distributed generation
  - Exported generation (half-hourly netting)

- **All other cost tests are based on all generation only**
  - Cannot accurately attribute a portion of DER system costs to exported generation

Evaluation Metrics: DER Growth

+ **DER growth will be evaluated using the following metrics**
  - Customer Adoptions
    - MW (by technology, by year)
    - # of systems (by technology, by year)
    - $ installations (by technology, by year)
  - Benefit-cost ratio (by technology, by year, by customer group)





Evaluation Metrics: Additional Results

+ The Public Tool will also include the following outputs:

- GHG impacts of DER (absolute tonnes, tonnes/MWh, $/tonnes)
- Utility rate changes due to DER
- DER utility avoided costs by component (energy, generation capacity, T&D, etc.)
- Net Benefit or Cost as % of utility revenue requirement

Percent of Cost of Service Recovery

- **Full Cost of Service is a utility term used in the General Rate Case (GRC) for allocating fixed costs to customers**
  - Aims to capture the full embedded cost of providing service to customers
- **2013 NEM study calculated the equal percentage of marginal cost (EPMC) cost of service for each customer bin**
- **In this study, we will calculate the cost of service for each customer bin using the cost-causation rate design**
  - The cost-causation rate captures the GRC full cost of service and all regulatory items
  - Includes costs to support CARE and other public purpose programs
- **The Public Tool will report % cost of service recovery for DER customers <u>before</u> and <u>after</u> installation of the DER system**

Cost of Service

- **The Public Tool will use the cost-causation rate to calculate the % of cost of service that DER customers pay:**

$$\%\ Cost\ of\ Service\ Recovery = \frac{Participant\ Payments\ to\ Utility}{Participant\ Full\ Cost\ of\ Service}$$

Where

$$Participant\ Payments\ to\ Utility = Utility\ Bills + DER\ Fees - Additional\ DER\ Compensation$$

And

$$Participant\ Full\ Cost\ of\ Service = Cost\text{–}causation\ rate \times Billing\ Determinants + DER\ Fees$$

DER-related Fees are those incremental costs paid by customers with DER

- May include interconnection upgrades, meters, engineering studies

Results Not Included in Tool

- **The public tool will not include the following outputs:**
  - Following the Distributed Generation (DER) cost-effectiveness methodology adopted in D.09-08-026, the RIM test will not include societal values
    - Societal values will be included as a user-defined input in the societal cost test
  - Percentage of cost of service paid by specific rate components cannot be modeled
    - All rate designs may not explicitly link cost of service components to specific rate components

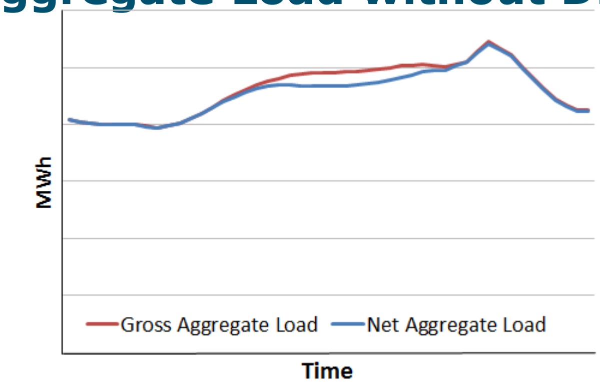
Avoided Costs

Avoided Costs Overview

- **Avoided utility costs estimate utility revenue requirement (RR) reductions**
- **Incremental utility costs (ex. DER integration costs) estimate utility RR cost increases and are <u>not</u> included in avoided costs**
  - Net RR change = incremental utility costs - avoided utility costs
- **The Public Tool calculates top-down aggregate RR reductions <u>and</u> bottom-up avoided costs by bin and technology**
  - Uses the avoided costs by bin and technology to calculate avoided costs
  - Uses the revenue requirement reductions to inform rates and bill savings

Avoided Utility Costs Overview

Aggregate Load without DER



Aggregate Load with DER

Revenue Requirement with DER

Revenue Requirement without DER

Δ Revenue Requirement

Incremental Utility Costs

Aggregate Avoided Utility Costs

DER Generation by Bin, technology, and time period

Customer Bin ID	kWh PV TOU 1	kWh Wind TOU 1
1	2,738	1,982
2	2,812	2,041
3	1,947	2,163
4	2,634	1,985
5	2,815	2,067
6	1,939	2,155
7	2,879	2,081
8	1,922	2,113

. . .

⋮

× **$/MWh Avoided Costs** by time period = **Avoided Costs by Bin**

$$\sum_{\substack{bins,\\ technologies}} Avoided\ Costs_{AC\ Component} = \Delta RR_{AC\ Component}$$

Avoided Utility Costs Overview

+ **For every avoided cost component:**

$$\sum_{\substack{bins,\\ technologies}} Avoided\ Costs_{AC\ Component} = \Delta RR_{AC\ Component}$$

+ **Where avoided components correspond to the following revenue requirement changes:**

Δ System capacity costs

Might not be exactly equal due to user ELCC and DER-related RBY overrides

Δ Subtransmission capacity costs

Δ Distribution capacity costs

Δ Generation costs – market purchases

Δ Generation costs - RPS purchases

Might not be exactly equal due to banking, borrowing, and curtailment – we are exploring this discrepancy

Δ A/S costs – net load-based

Δ Carbon allowance costs

Δ Costs associated with losses

Avoided Utility Cost Components

Component	Value Description
Thermal Generation	Estimate of marginal wholesale value of energy (valued at $0/MWh when renewables are on the margin)
Ancillary Services	Reduced system operations and reserves required for electricity grid reliability
RPS Generation & Integration Costs	Cost reductions from being able to procure and integrate a lesser amount of RPS assets
Losses	Estimate of value of additional marginal wholesale value of energy due to losses between the point of the wholesale transaction and the point of delivery
CO2 Emissions	The cap-and-trade allowance revenue or cost savings due to reductions in carbon dioxide emissions (CO_2)
System Capacity	The reduced reliability-related cost of maintaining a generator fleet with enough capacity to meet annual peak loads and the planning reserve margin
Distribution Capacity	Reduced need for distribution capacity expansion to meet customer peak loads
Subtransmission Capacity	Reduced need for subtransmission capacity expansion to meet customer peak loads

Local Capacity Value

- DER located in transmission-constrained local capacity resource areas could theoretically provide local capacity value
- The CAISO 2019 Local Capacity Technical Analysis shows negligible capacity deficiency in the LCR zones in 2019
- Unless parties have data sources for projecting local capacity requirements beyond 2019, we propose not to model local capacity value

Avoided Cost User Inputs

- **User inputs that impact generation (RPS and thermal), losses, carbon, and A/S avoided costs:**
  - RPS target (33%, 40%, 50%)
  - Cost of utility-scale RPS assets ($/MWh)
  - Natural gas prices
  - Ancillary services (A/S) cost as a % of market energy
  - Carbon cap-and-trade allowance trajectory
- **User inputs that impact capacity avoided costs:**
  - Cost of the marginal capacity resource (assumed to be a CT)
  - Heat rate of the marginal capacity resource
  - Resource balance year (RBY) for DER accounting
    - May cause discrepancies between the avoided costs and the RR
- **User inputs that impact T&D capacity avoided costs:**
  - % of distribution marginal costs that can be avoided by DER
  - % of subtransmission marginal costs that can be avoided by DER

Avoided Utility Costs

System Capacity
Subtransmission
Distribution
Net Integration Benefits
Carbon Allowances
Losses
Non-RPS Generation
RPS Generation

Avoided Costs: Utility Energy Costs

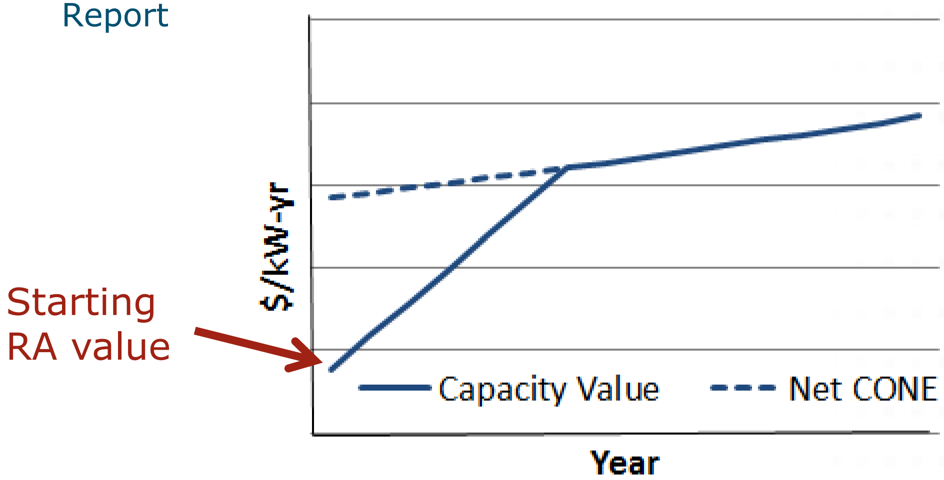
+ **Utility energy costs include costs of RPS and non-RPS generation**
+ **In avoided cost calculations, annual DER avoids annual RPS and non-RPS market purchases based solely on the annual RPS requirement**
  - Because net load reduction reduces the RPS compliance obligation
  - Ex. If RPS requirement is 33% in a given year, 1 MWh of DER avoids 333 kWh of RPS compliant energy and 667 kWh of non-RPS market purchases
+ **RPS avoided cost in a given year equals the annual average LCOE ($/MWh) of the RPS resources added in that year**
  - Levelized over the economic life of the RPS asset
+ **Market energy costs driven by annual marginal market heat rates and natural gas price trajectory**
  - Marginal market heat rates calculated within the Public Tool

Avoided Costs: Losses, Carbon, and Ancillary Services

- **Energy loss factors are applied to avoided wholesale market generation costs to obtain energy costs at the meter**
  - Note that the RPS requirement is based on retail load and is not grossed up for losses
  - Loss factors provided by the IOUs
- **Carbon allowance price trajectory is a user input**
- **Carbon savings (tonnes) calculated based on marginal market heat rates**
- **Ancillary service costs are modeled as a % of market energy costs**
  - This is a user input
  - Default is 1% based on CAISO's *2012 Annual Report on Market Issues and Performance*

Avoided Costs: System Capacity Costs

+ **Model estimates annual \$/kW-yr marginal cost of maintaining a generator fleet with enough capacity to meet annual peak loads + the planning reserve margin**
  - Prior to the resource balance year (RBY), equals value of reduced Resource Adequacy (RA) procurement
  - After the RBY, equals the capacity payments that would have been paid to new generation capacity (net cost of new entry, or net CONE)
  - Annual RA value estimates based on linear interpolation between the assumed 2012 RA value and the net CONE in the RBY
    - 2012 value is the median 2012 RA value from the CPUC 2012 Resource Adequacy Report



Avoided Costs: System Capacity Costs

+ **Resource Balance Year (RBY) is an output of the revenue requirement calculation, reflecting when the CAISO system supply equals the CAISO system demand plus reserve margin**
  - Public Tool will calculate RBY with and without DER
+ **Users can select a different <u>DER-related RBY</u> for use in avoided cost calculations**
  - May cause inconsistencies between the RR and avoided costs
+ **Recall that users can also change the $/kW-yr capacity value by overriding the following inputs:**
  - Cost of the marginal capacity resource (assumed to be a CT)
  - Heat rate of the marginal capacity resource

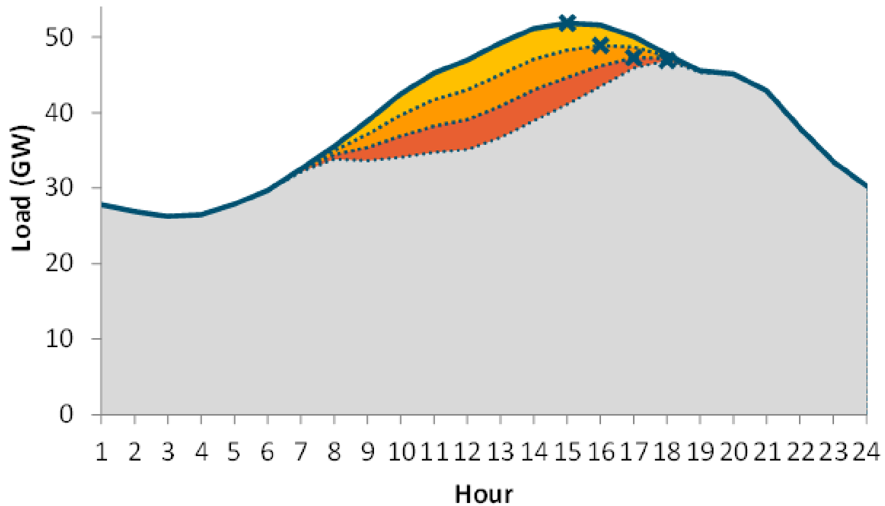
Avoided System Capacity Costs: ELCC

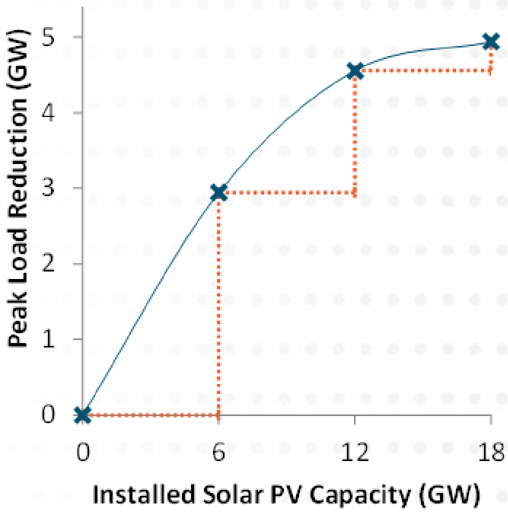
- **The system capacity that can be avoided by DER generation is calculated using the effective load carrying capability (ELCC)**
- **ELCC of a DER system is the amount of system load that can be added after the addition of the DER while maintaining the same level of system reliability**
- **ELCC value of an individual DER system is driven by:**
  - Coincidence of DER penetration with net load (gross load less the existing portfolio of non-dispatchable resources)
  - Production variability
- **By default, ELCC values are calculated using E3's public RECAP* model**
- **Users may also directly specify % of system capacity that is avoidable by each DER technology**

*https://ethree.com/public_projects/recap.php

Avoided System Capacity Costs: ELCC Allocation

+ **A DER system's ability to reduce net load changes as other resources are added to the system**
  - For example, while a small amount of solar PV has a relatively large impact on peak, it also shifts the "net peak" to a later hour in the day, causing additional solar PV to have a smaller impact on net peak:





+ **The Public Tool can allocate ELCC in two ways:**
  - Vintaged: Each vintage of DER receives its marginal ELCC value at the time of installation throughout its economic life
  - Non-Vintaged: Individual ELCC values for all vintages are updated every year as RPS and DER penetrations change

Avoided Costs: Subtransmission Capacity

- **Model will use one average marginal subtransmission capacity value ($/kW-yr) by utility**
  - Values from utility GRC distribution capital budget plan data
- **The $/kW-yr value will be allocated across the year based on peak capacity allocation factors**
  - DER technologies and bins will receive different total avoided distribution values based on coincidence with subtransmission congestion
- **User can input an override for % of subtransmission marginal costs that can be avoided by DER**

Avoided Costs: Distribution Capacity

- **Average marginal distribution capacity costs ($/kW-yr) developed from the utility GRC distribution capital budget plans**
- **The $/kW-yr value is allocated across the year based on peak capacity allocation factors**
  - DER technologies and bins receive different total avoided distribution values based on coincidence with distribution congestion
  - Allocation factors based on substation load shapes provided by the IOUs, aggregated to climate zones
- **User input can override the % of distribution marginal costs that can be avoided by DER**
- **We are looking into assigning distribution "hot spots," a higher distribution capacity value than other locations**

Avoided Costs Not Modeled in Public Tool

- **The following cost-related issues are not included in the Public Tool because the tool addresses them in an alternative way to those suggested by parties**
  - Operating parameters of CTs and CCGTs
    - Energy and capacity costs can be altered directly, obviating the need to modify these inputs
    - Generation capacity costs will be allocated based on ELCC
  - Allocation of T&D costs
    - T&D costs are a small share of total avoided costs and T&D allocations in the Public tool will be necessarily generalized
  - Marginal heat rates
    - These are calculated in the Public Tool and take into account net thermal generation in each TOU period

Avoided Costs Not Modeled (con't)

- Gas pipeline infrastructure costs will not be modeled
  - Users may accommodate these costs via a generation capacity cost scenario
- Renewable generation-related externalities, such as natural gas price hedges, water costs, and pollution control equipment will not be modeled separately
  - These are already accounted for in the avoided marginal resource costs, and will not be added as a separate avoided cost component to avoid double counting.
- Avoided land use impacts will not be modeled
  - Users may enter a value for these in the user-defined societal cost test inputs

Utility Costs

Utility Costs

- **Three primary utility costs of DER**
  - Integration costs
  - Billing costs
  - Interconnection costs
- **All three of these components are from input assumptions**
  - Integration costs are approximated from other studies
  - Billing and interconnection costs are directly from utilities
- **Users will be able to make alternative assumptions on all three components**

DER System Costs

System Costs - DER

+ **DER system costs include the following components:**
  - Capital costs
  - Fixed and variable operations & maintenance costs, property taxes, insurance, fuel costs
  - Finance costs (upfront purchase or third-party lease/PPA)
  - Incentives
  - Income tax (including ITC, PTC, MACRS, where relevant)
+ **All cost inputs and trajectories over time are user flexible**
+ **In the cost-benefit calculations, cost equals the present value of all costs associated with owning and operating the DER system**
  - Costs above
  - Incremental participant costs (meters, interconnection, if applicable)

Questions

Break

11:15 am – 11:30 am

Data Sources
11:30 am – 12:15 pm

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Overview of Data Sources Section

- **Data sources describe the sources we propose to use to establish default values in the tool**
- **All of the default values can be fully modified by users**
- **Data Sources**
  - Adoptions
  - Avoided Costs
  - DER Costs
  - Revenue Requirements

Adoption Module

+ **Adoption module methodology is largely based on NREL's *Solar Deployment System Model* (SolarDS) that simulates the potential adoption of solar PV**
  - http://www.nrel.gov/docs/fy10osti/45832.pdf
+ **Default model parameters will be calibrated to match historical financial proposition and adoption rate relationships**
+ **Technical/Achievable potential**
  - Percent of customers eligible to install a particular technology, by technology & class
  - NREL: Supply Curves for Rooftop Solar in the United States
    - http://www.nrel.gov/docs/fy09osti/44073.pdf
  - NREL: An analysis of the Technical and Economic Potential for Mid-Scale Distributed Wind
    - http://www.nrel.gov/wind/pdfs/midscale_analysis.pdf
  - NREL: U.S. Renewable Energy Technical Potentials
    - http://www.nrel.gov/docs/fy12osti/51946.pdf

DER Cost and Performance: Solar

Costs

- Cost projections vary by install size (< 10 KW , > 10 kW)
- Default 2014 costs utilize California values from the 2014 LBNL Tracking the Sun report
  - http://emp.lbl.gov/sites/all/files/lbnl-6808e_0.pdf
- Cost trajectory utilizes the EIA global forecast PV installation projections in conjunction with component specific learning rates
  - Soft costs: 15%
  - non-module hard costs: 15%
  - module costs: E3 historical regression of cost to installation

Performance from 2013 NEM Study data

- Simulated solar output based on geography, array size, and panel orientation using irradiance data from Clean Power Research public tool
- Simulation results are compared with actual metered data for accuracy

DER Cost and Performance: Small Wind

+ Costs

- Cost projections vary by install size (< 10 KW, > 10 KW)
- Default capital costs use 2013 EIA Distributed Generation System Cost Report
  - http://www.eia.gov/analysis/studies/distribgen/system/pdf/full.pdf

+ Performance

- Simulations based on 10 minute wind data from NREL’s Western Wind Dataset, NREL’s geospatial wind class zones, and various distributed wind turbine power curves
  - http://wind.nrel.gov/Web_nrel/
  - http://www.nrel.gov/gis/data_wind.html
  - http://www.wind-power-program.com/download.htm#database

DER Cost and Performance: Biomass, Biogas, and Fuel Cells

+ Costs

- $/kW capital cost not differentiated by system size
- Biogas and biomass default capital costs set using 2013 *Small-Scale Bioenergy Resource Potential Cost Report* for CPUC
  - http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M081/K583/81583311.pdf
- Fuel Cell default capital costs set using 2014 *Lazard LCOE Analysis*
  - http://www.lazard.com/PDF/Levelized%20Cost%20of%20Energy%20-%20Version%208.0.pdf

+ Performance

- Output assumed to be constant in all hours

DER Cost & Performance: PV+Storage Dispatch Shapes

+ **The Public Tool will be seeded with six pre-processed PV+Storage dispatch shapes for each representative customer bin:**
  - One monthly maximum demand charge minimization dispatch
  - Two TOU energy rate arbitrage dispatches
    - One that assumes an afternoon on-peak period
    - One that assumes an early evening on-peak period
  - Three grid benefit maximization dispatches
    - One per each of the following default policy scenarios:
      - 33% RPS
      - 40% RPS
      - 50% RPS
+ **The Public Tool will only allow adoption of PV+storage dispatched for each of these cases when the scenario is applicable**

DER Cost & Performance: Storage Technology

- **Sources:**
  - *SANDIA Report: EPRI/DOE 2013 Electricity Storage Handbook in Collaboration with NRECA.* Table B-30: Li-ion Battery Systems for Distributed Energy Storage.
  - SGIP requirements
- **Assumptions:**
  - AC-AC roundtrip efficiency: 89%
  - Discharge capacity, charge capacity: PV nameplate capacity
  - Discharge duration: 3 hours

DER Cost and Performance: Tax & Incentives

+ Taxes and Incentives

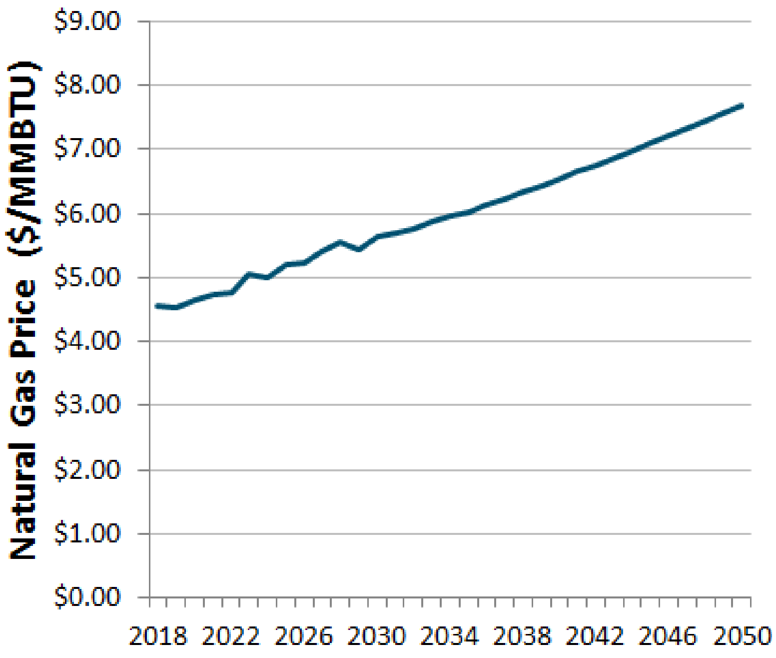
- Current income tax regulations
  - For example, ITC steps down to 10% in 2017
- SGIP assumed renewed at current levels and for current eligible technologies
- CSI assumed to be completed and not included

Avoided Costs

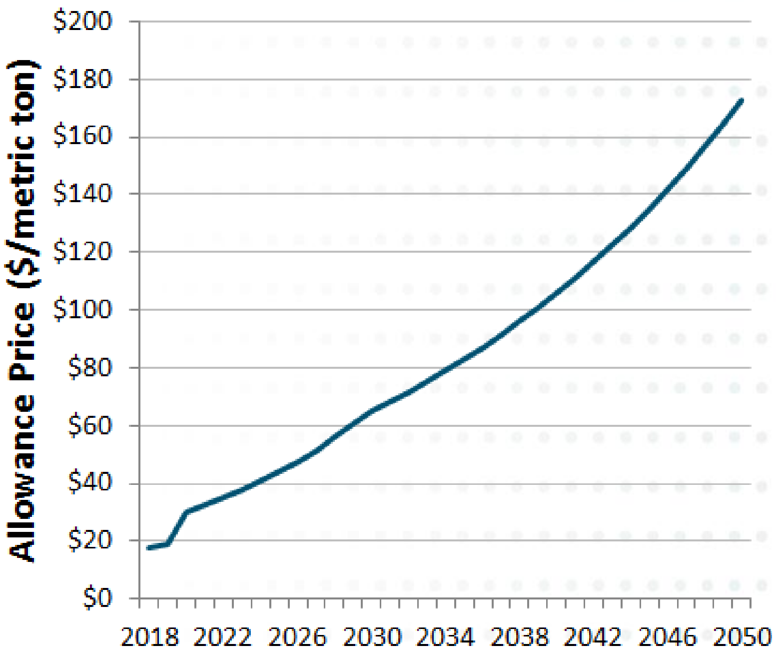
- **Distribution and Subtransmission capacity costs**
  - Utility GRC distribution capital budget plan data
- **Ancillary services**
  - 2013 NEM Study
- **Losses**
  - Provided by IOUs
- **Interconnection costs**
  - Utility interconnection cost advice letters
- **Nonbypassable charges**
  - GRC data

Natural Gas Prices and Carbon Allowance Costs

+ **Natural Gas**



+ **Carbon Allowance**



All dollars are nominal

+ Natural gas price and carbon allowance per 2013 IEPR mid trajectories
+ Market heat rates calculated using 2014 RPS Calculator methodology
  - Shaped using 2014 CEC Title 24 Plexos hourly curves

RPS Resource Costs

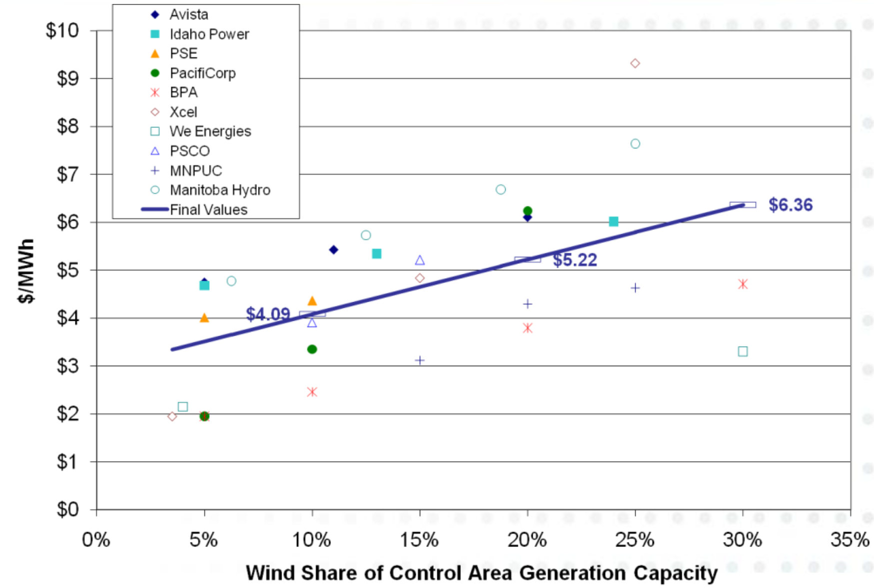
- **Source: 2014 RPS Calculator**
  - In-state portfolio geography scenario
- **33%, 40% and 50% RPS scenarios**
  - Portfolio composition varies by technology type
  - Penetration limited by technical potential
- **Learning curves for wind and solar technologies**
  - Costs for other technologies remain flat (real dollars)

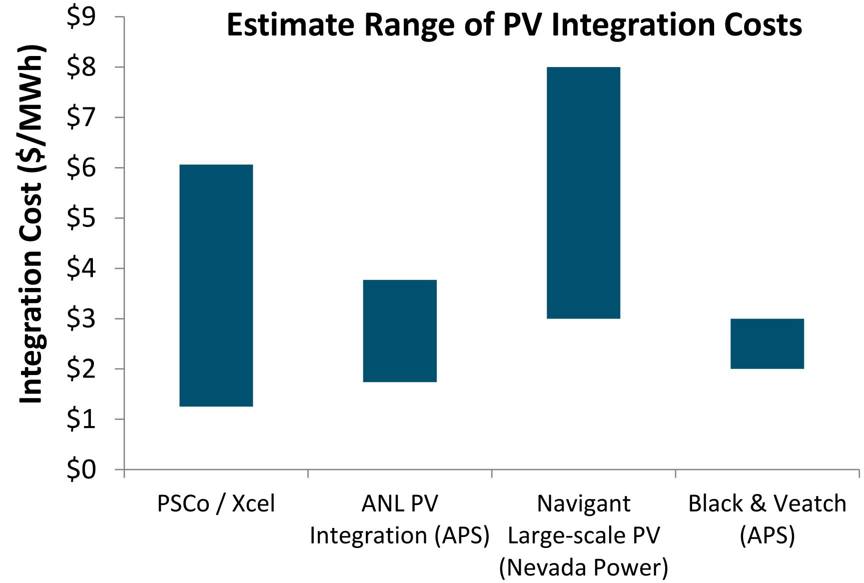
Revenue Requirements

- **Used publicly available data to develop revenue requirement projections for each utility**
  - Distribution and generation rate base and O&M
    - Most recent GRC decisions for each utility
  - Cost of Capital Mechanism
    - D. 13-03-015
  - Policy Scenarios: electric vehicles, ZNE, energy efficiency
    - 2013 IEPR
  - System capacity resource supply (MW)
    - 2014 LTPP
    - Adjusted per public Tool load-resource balance modeling (loads vary by policy scenario)
  - Capacity cost
    - 2012 CPUC Resource Adequacy Report
    - 2012 CAISO Annual Report on Market Issues and Performance

Integration Costs

+ **Wind and solar integration costs will be directly tied to utility-scale RPS and DER penetration levels**
+ **Numerous studies have attempted to estimate these incremental integration costs**
+ **Estimates range from approximately $2 -8 per MWh**





Class Usage: Customer Segments

- **8 customer segments for revenue requirement cost allocations**
  - Residential (including CARE)
  - Small Commercial
  - Medium Commercial
  - Large Commercial
  - Industrial (not applicable for SDG&E)
  - Agricultural
  - Streetlighting
- **Streetlighting not modeled for NEM adoptions**

Development of 2012 Hourly Class Usage by Customer Segment

- **Synthesized 2012 hourly load shapes by utility and customer segment**
  - PG&E: PG&E-provided 2012 customer segment load shapes and 2012 dynamic load profile data
  - SCE: 2013 customer segment load shapes and 2013 dynamic load profile data
    - 2013 day mapped to 2012 day taking into account calendar quarter & day type (weekday/weekend/holiday)
    - 2013 class share of daily load applied to 2012 hourly load shape
  - SDG&E: most recent 365 days dynamic load profile data
    - Most recent 365 days mapped to 2012 day taking into account calendar quarter & day type (weekday/weekend/holiday)
    - Most recent 365 days class segment share of daily load applied to 2012 hourly shape to create hourly loads by customer segment

Proposed Issues not Modeled Due to Data Limitations

+ **Small hydro and in-conduit hydro technologies**
  - Provided the hourly generation shape for small or in-conduit hydro matches the generation shape of one of the technologies included in the tool, users may modify technology inputs to model adoption of these technologies
+ **Specific customer types (i.e., schools, public agencies)**
  - Users may be able to utilize customer bin data to model specific customer types, to the extent that bin data load profile is similar
+ **NEM-A (NEM aggregation)**
  - Users will be able to estimate the impact of NEM-A by using a capital cost reflective of a large solar system, to the extent that the agricultural customer "bin" data can represent the usage of aggregated smaller accounts
+ **West facing panel attribute in bins**
  - Customer bins will not be selected based on this attribute

Questions

Lunch
12:15 pm – 1:15 pm

Public Tool
1:15 pm – 2:30 pm

Overview of Proposed Approach
Questions 1-2

Modeling Approach
Questions 3-9

Data Sources
Questions 10-11

Public Tool
Questions 12-20

Pricing Mechanisms and Rate Design
Questions 21 - 27

Other Issues
Question 29

Analysis Term

+ **Model will calculate adoptions from 2012-2025**
  - The model will use historical data where available as inputs and to calibrate certain assumptions and parameters
+ **The model will calculate the remaining lifecycle cost impacts for all DER systems once new residential rates are effective**
+ **Model assumes NEM successor tariff will take effect in 2017**
+ **Grandfathered NEM systems include all historical DER installations and forecasted adoptions before NEM successor tariff is enacted**
+ **DERs installed from 2017-2025 will be compensated through the NEM successor tariff and may be subject to alternative rate structure and/or additional rate charges**
+ **To calculate lifecycle cost impacts, the model will calculate utility rates and DER avoided costs through 2050**

Public Tool Overview
Step 1: Determine Rates

User
Scenario Selection
2030 RPS Target
EE Penetration
DR Penetration
EV Penetration
ZNE Home Targets

User
Cost Driver Selection
Natural Gas Prices
Carbon Prices
Resource Balance Year

User
Rate Inputs
Rate Structure
Rate Levels
NEM Successor Tariffs

Pre-processed billing determinants by rate structure

Revenue Requirement Allocation Factors

Rate Outputs
Model solves for a user-designated rate component in order to true up other user rate inputs, billing determinants, and total revenue requirement

Public Tool Overview
Step 2: Determine DER Costs

User Financing Assumptions
Financing Structure
Tax Assumptions
Incentive Assumptions

User Cost Inputs
Capital Costs
O&M Costs
Fuel Costs
Escalation rates

Cost Outputs
Model solves for present value of all lifecycle costs of the DER system

Public Tool Overview
Step 3: Customer Benefits

Pre-processed billing determinants determinant reductions

Previously solved for rate levels

DER Compensation

Benefit Outputs

Model solves for present value of all lifecycle financial benefits (bill savings + DER compensation)

Public Tool Overview
Step 4: Adoption Module

Previously Calculated DER Customer Costs

Previously Calculated DER Customer Financial Benefits

User Inputs
Adoption parameter inputs

Adoption Level Outputs
Model solves for annual DER installations by technology

Loop
This adoption calculation process repeats through all customer bins through all years

Public Tool Overview
Step 5: Avoided Costs

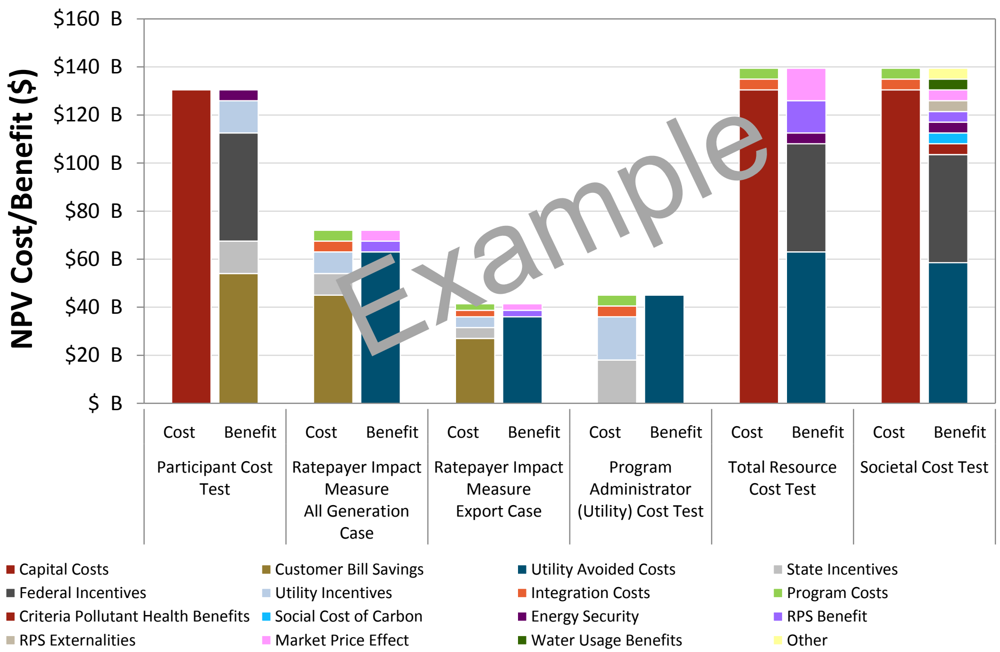
User
Avoided Costs Inputs
note: these were already used to determine rates in Step 1

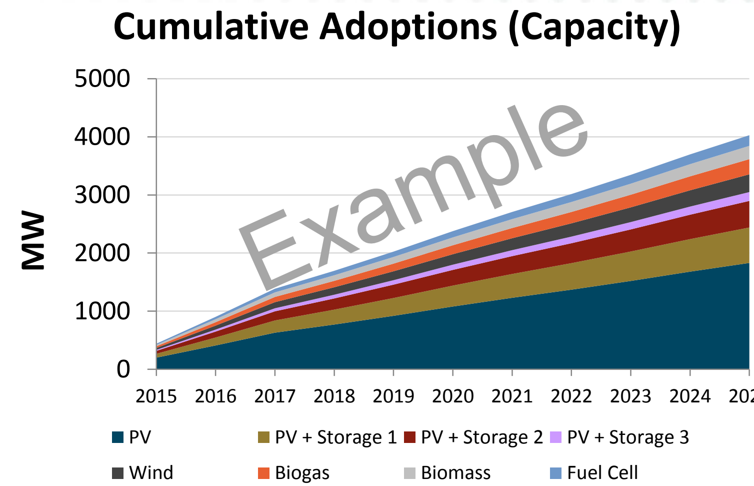
DER adoption outputs

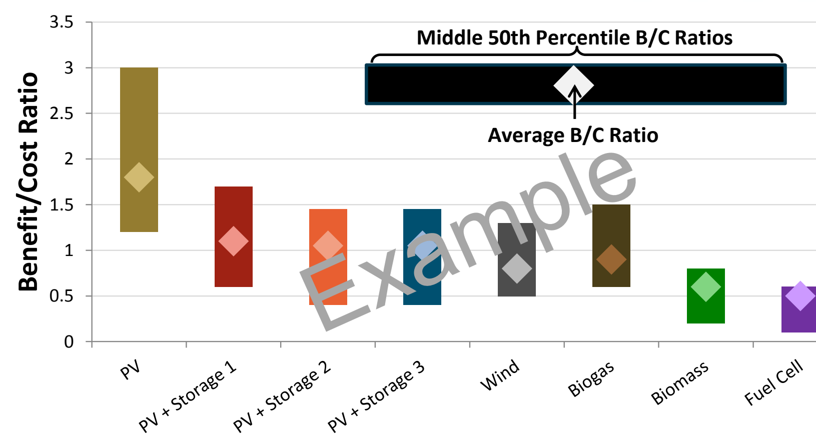
Avoided Cost Outputs
Model calculates utility avoided costs attributable to each DER installation by customer bin, by technology, by year (vintage)

Public Tool Overview
Step 6: Results

+ **Model shows various results and output metrics including**
  - DER adoption penetrations
  - Cost impacts of DER adoptions
  - Other (see evaluation metrics)

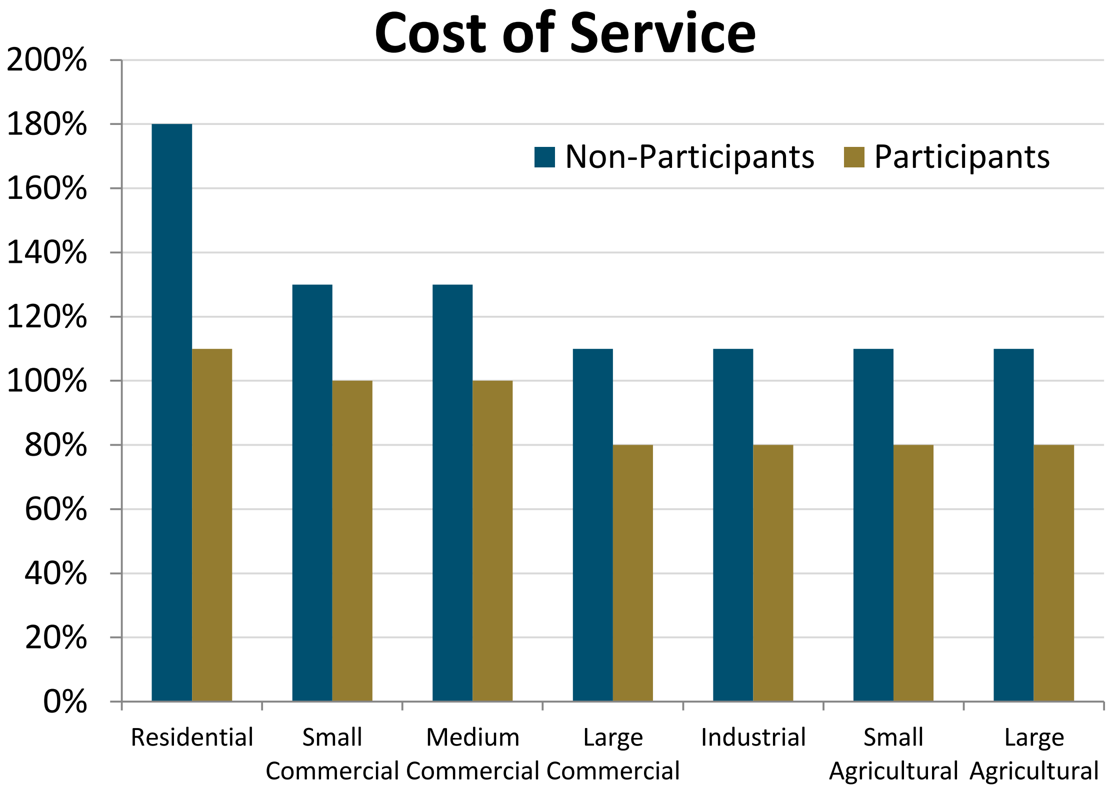






Example Cost of Service Output

- Model will report share of cost of service paid by customer class for both participants and non-participants



Public Tool Interface: Basic Policy Inputs

+ User-defined policy scenarios

- RPS (33%, 40%, or 50% in 2030)
- EE, DR
- Electric Vehicles
- Zero Net Energy homes
  - Adds policy-driven incremental EE and rooftop solar adoptions
- Exported distributed generation counts towards RPS and receives avoided cost value of category 1 REC (doesn’t change load)
- Users can change default values for TOU periods associated with EE, DR, and EVs

Public Tool Interface: Basic Rate Design Inputs

+ Residential Class

- User selects default rate structure and any policy changes due to the CPUC Residential Rates OIR proceeding

+ All Rate Classes

- User sets NEM successor tariff options including
  - DER compensation structure
  - Other rate structure modifiers available under CA AB 327

Public Tool Interface: Advanced Rate Inputs

- **All Basic Interface rate designs, plus**
- **Users may alter every rate component except one (necessary to collect revenue requirement)**
- **Users can model participant-specific designs that are different from non-participant default design**
  - i.e., TOU for DER participants, tiered for non-participants and grandfathered participants

Public Tool Interface: DER System Cost Inputs

- **6 technologies for cost purposes**
  - PV, PV + storage, wind, biomass, biogas, fuel cell
- **Costs for small, medium and large systems**
- **Users are able to change DER system cost inputs for each technology**
  - Capital cost
  - Operating cost
  - Finance structure
  - Tax benefits
  - Incentives

Revenue Requirement

Public Tool Interface: Revenue Requirement Inputs

- **Most revenue requirement input assumptions may be changed by users**
- **Revenue requirement calculations are performed for each utility in nominal dollars through 2050**
  - Energy and capacity costs to serve load
  - Distribution and generation rate base
  - Nonbypassable charges
  - Taxes
  - Cost of capital
- **To model bundled service revenue requirements, Public Tool calculates**
  - CAISO system capacity balance
  - Delivery and bundled usage and cost allocations

Revenue Requirements Supply: RPS Energy

- **33%, 40% and 50% RPS portfolios established per proportion of energy generated by technology type in each year**
  - Drives nameplate capacity of each technology installed in each year when new RPS resources are required
  - Banking and borrowing logic included
  - Retirement logic included
  - Approximation for degradation
- **Portfolio composition can be altered by users**
  - Logic fully active – altered portfolios impact costs, ELCC, etc.

Revenue Requirements Supply: Other Energy

- **UOG hydro and nuclear energy**
  - SONGS retired in 2012
  - Diablo retired 2024, users can change this assumption
- **Market purchases**
  - IOU bundled load net of DER, RPS, hydro and nuclear energy is costed per Public Tool marginal heat rate in applicable TOU period
  - Incorporates policy-driven load changes
  - One market heat rate analysis is included in the Tool
    - Combines NP15 and SP15
  - Users cannot change market heat rates

Revenue Requirements Supply: Capacity

- **Capacity requirements are based on an annual accounting of CAISO loads and supply incorporating**
  - CAISO new fossil units
  - CAISO RPS units
  - CAISO supply-side DR
  - Imports
- **CAISO residual annual capacity needs met by:**
  - Market resource adequacy contracts prior to resource balance year
  - New capacity units from and after RBY
- **Bundled customers pay their share of capacity costs in revenue requirements calculation**
- **Users cannot change RBY in revenue requirements**

Revenue Requirements
Other costs

- **Remaining utility revenue requirement costs, including:**
  - Energy efficiency
  - Nuclear decommissioning
  - DWR Bond Charge
  - CARE
- **Allocated among bundled and delivery customers**

Revenue Requirements
Participating Customer Costs

- **Incremental costs paid by participants are not included in revenue requirements**
  - Meters when paid by participating customers
  - Interconnection costs when paid by participating customers
- **Incremental costs related to participating customers that are included in revenue requirements include**
  - Interconnection cost & meters (if participant does not pay)
  - Billing costs
  - Integration costs

Revenue Requirement Cost Allocation to Customers

+ **Once the revenue requirement is calculated, it must be allocated to customer classes for rate design purposes**
+ **The Public Tool's default revenue allocation to segments will reflect full EPMC (equal percentage of marginal cost)**
  - Model will calculate allocation factors annually
  - No capping in default values
+ **User will have the option to cap EPMC allocations based on current actual average segment rates**
  - This scenario would reflect circumstances such as rate settlement agreements or policies related to rate levels

Cost allocation: Generation Marginal Cost

- **Generation-related revenue requirement allocated by sum of energy and generation capacity marginal costs**
  - Energy marginal costs based on Public Tool marginal heat rates and RPS costs
    - Includes impact of avoided energy costs by TOU period due to non-dispatchable and RPS resources as well as policy scenarios
  - Customer segment peak capacity will be based on customer segment average load during the system peak TOU period
    - Will be adjusted as necessary by diversity factors from GRC filings (to better match GRC data)

Cost Allocation: Customer Costs and T&D

- **Customer marginal costs and T&D marginal costs are based on utility GRC marginal costs, with user ability to alter**
  - Escalated over time in the Public Tool
- **T&D peak load based on customer segment diversified peak demand at the time of the segment peak**
  - Diversity factor from GRC filings will be applied to segment diversified peak to calibrate to current relationship between diversified peaks and T&D peaks

Participating Customer Billing Determinants

DER Technologies

+ **The Public Tool will evaluate eight different DER technologies:**
  - PV
  - PV + 3-hr duration storage (energy rate arbitrage)
  - PV + 3-hr duration storage (demand charge minimization)
  - PV + 3-hr duration storage (maximize grid benefits)
  - Wind
  - Biogas
  - Biomass
  - Renewable fuel cell

Customer Bins

- All customers who may or may not install DER are grouped into representative customer bins
- There are enough customer bins to capture diversity in usage and generation profiles
- The Public Tool uses the customer bins to calculate bill savings, avoided utility costs, and adoption by bin
- Each customer bin is assigned a weight that represents the % of all customers represented by that bin
  - Weights are based on historical adoption
  - The historical residential weights are then adjusted to capture the true size (gross usage) distribution among all utility customers
    - Corrects for the fact that historic residential rate design caused disproportionate adoption among large customers

Customer Bins & DER Sizing

- **The model assumes that each representative customer bin could install any DER technology**
  - Total adoption is subject to economic and technical potential
- **The model will evaluate three sizing options for each DER technology:**
  - 33% of annual usage
  - 67% of annual usage
  - 100% of annual usage
- **The Public Tool will be seeded with characteristics and billing determinants for each representative customer bin, DER technology, and DER size**

Calculation of Customer Bins

- **Customers in a given bin are homogenous with respect to the following characteristics:**
  - Utility
  - Climate / location (climate zones)
  - Customer categories
  - Electric heating (Res customers only)
  - CARE (Res customers only)
- **Customers are clustered by a number of usage and generation characteristics, primarily:**
  - Annual usage
  - Load factor
  - Afternoon gross usage
  - Evening gross usage
  - Wind capacity factor
  - Exported usage with a mid-sized PV resource

Adoptions

Public Tool Interface: Adoption Module Inputs

- Forecasted adoptions are based on user-specified parameters
- These will be calibrated to historical adoptions, but are user-flexible
- Adoption forecast can also be entirely overridden by user-input forecast

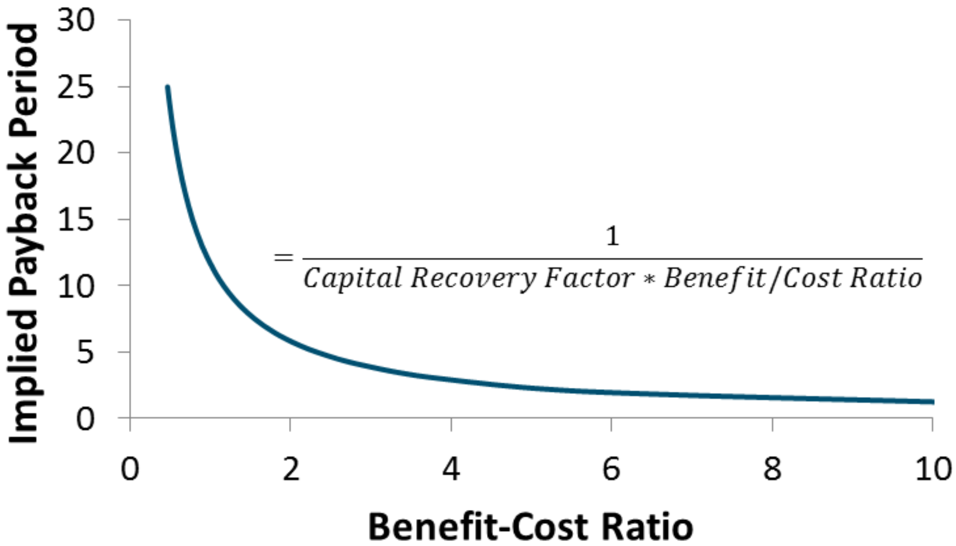
Adoption Module

- **Adoption module purpose: <u>How much and how fast will customers adoption potential DER options?</u>**
  - Methodology based on NREL's *SolarDS* model*
- **Step 1) Determine financial proposition of various DER options**
  - Measured as benefit-cost ratio > converted to implied payback period
- **Step 2) Forecast maximum market share by technology**
- **Step 3) Allocate technology market shares to ultimate adoptions**
- **Step 4) Calculate how fast adoptions approach the ultimate market share**

*http://www.nrel.gov/docs/fy10osti/45832.pdf

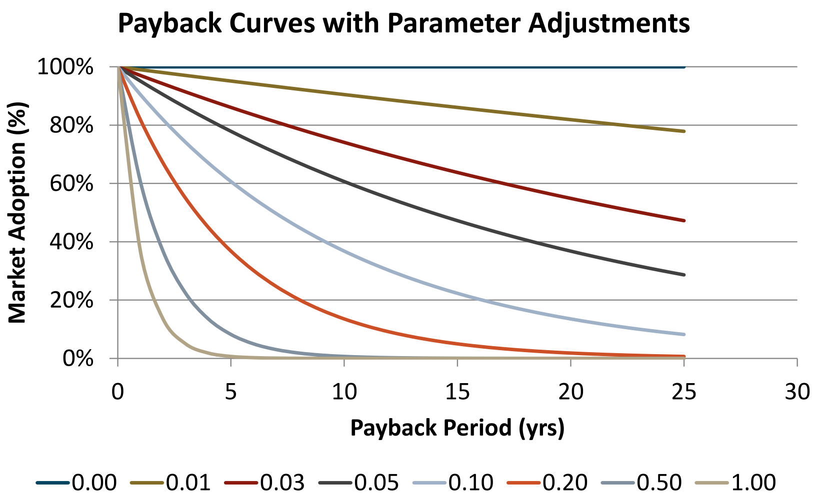
Step 1) Financial Proposition

- **Financial proposition measured as benefit/cost ratio**
  - = PV (Utility Bill Savings and/or DER compensation) / PV (Cost of the DER System)
- **Benefit-Cost ratio is converted to implied payback period via the following function**



Step 2) Forecast Max Market Share

+ **Using a payback curve, maximum market share is forecasted for all possible technologies via the following function**
  - = exp(-payback sensitivity parameter * payback period)



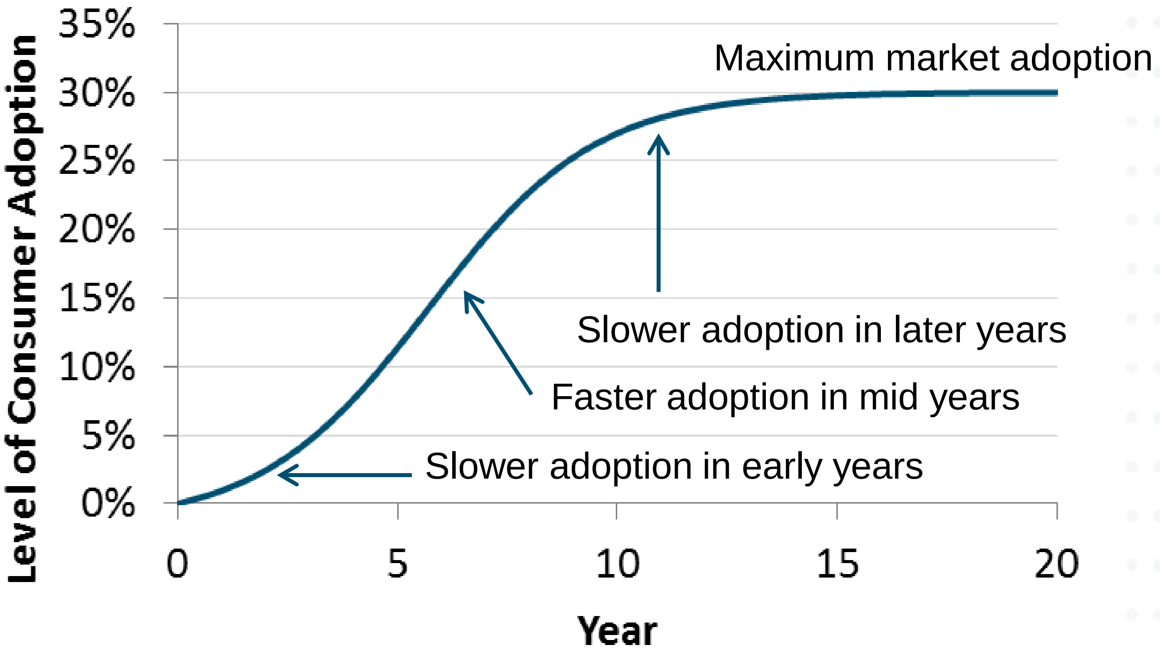
+ **Maximum market shares are scaled by the technical potential of each technology/customer class**

Step 3) Allocate Technologies

- **Forecasted maximum market adoptions are then allocated proportionally such that total installations across technologies sum to the installation forecast for the single highest projected technology**
- **Example: One technology's market potential is forecasted to be 10%**
  - Ultimate adoptions for that technology are forecasted to be 10%
- **Example: Two technologies' market potentials are forecasted at 10%**
  - Since an individual customer can only install one technology, half of all adopters are assumed to install one technology and half the other
  - Ultimate adoptions for each technology are forecasted to be 5%
    - 5% + 5% = 10%
- **Example: Three technologies' market potential are forecasted at 10%, 10% and 5%, respectively**
  - Some adopters might prefer the 5% option, but less than either of the 10% options
  - Ultimate adoptions for each technology are forecasted to be 4%, 4% and 2% which keeps projected adoptions proportional to the original projections
    - 4% + 4% + 2% = 10%

Step 4) Calculate Rate of Adoption

- **An "S-Curve" shown below is used to govern the rate at which customer adoptions approach the maximum market share**



Questions

Break

2:30 pm – 2:45 pm

Pricing Mechanisms and Rate Designs 2:45 pm– 4:00 pm

Overview of Proposed Approach
Questions 1-2

Modeling Approach
Questions 3-9

Data Sources
Questions 10-11

Public Tool
Questions 12-20

Pricing Mechanisms and Rate Design
Questions 21 - 27

Other Issues
Question 29

NEM Compensation: Rate Design

- **Users specify:**
  1. The default residential rate design
     - Applies to grandfathered customers and non-participants
  2. The NEM Successor Tariff for each customer segment
     - Applies to customers who install eligible DER after 2017
- **These rate designs may be identical or may have no commonalities**
- **Applicable rate by customer type:**

	Customers without DER	Grandfathered Participants	New Participants
Residential	**Default Residential Rate** Proceeding: CA Residential Rates OIR, 2012 - Present	**Default Residential Rate** Proceeding: CA Residential Rates OIR, 2012 - Present	**NEM Successor Tariff** Proceeding: R1407002
Non-residential	**Default Rate for Applicable Customer Segment** Proceeding: None (Advanced input only)	**Default Rate for Applicable Customer Segment** Proceeding: None (Advanced input only)	**NEM Successor Tariff** Proceeding: R1407002

Note - Although there is no current relevant proceeding, advanced users may also alter the default non-residential rate design assumptions

“Menu” of NEM Alternative Tariff Structures

- **Public tool users can choose from one of four DER compensation mechanisms for NEM Successor Tariffs:**
  - Bill credits based on the underlying retail rate structure applied to all DER generation (“Full Retail Rate Credit”)
  - Cost-based compensation (“Cost-based Comp”)
  - Value-based or market-based compensation (“Value-based Comp”)
  - Bill credits based on underlying retail rate structure applied to DER generation consumed on customer premise + value-based compensation for exports (Retail Rate Credit + Value-based Export Comp)
- **For each model run, this choice applies across all utilities, customer segments, and DER sizes**
  - Retail rate and compensation levels may vary by utility and customer segment

Overview of DER Compensation “Menu” Items

Menu:
- **Full Retail Rate Credit**
- **Cost-based Comp**
- **Value-based Comp**
- **Retail Rate Credit+ Value-based Export Comp**

+ **Under Full Retail Rate Credits, rate design and customer usage determine DER compensation**
  - Full Retail Rate Credit compensates all DER generation at retail rate levels
+ **Cost- or Value-based Compensation decouples DER compensation from retail rates and customer usage**
  - Removes consideration of DER compensation impacts from rate design
  - Usage does not impact DER sizing (beyond sizing requirements)
+ **Cost- or Value-based Compensation may or may not have different tax implications than Retail Rate Credits**

Rate Design Options

Menu:
- ★ Full Retail Rate Credit
- Cost-based Comp
- Value-based Comp
- Retail Rate Credit+ Value-based Export Comp

- **Rate design components available for default residential rates:**
  - Energy charges ($/kWh; see next slide)
  - Fixed charges (capped at $10/month, tied to CPI)
  - Minimum bill ($/month with month-to-month rollover)
- **Default non-residential rate designs reflect current default non-residential rate structures**
  - Energy charges are flat or TOU
  - Demand charges, fixed charges, and minimum bills apply
- **Default residential rate design is a <u>user input</u>**
- **Default non-residential rate designs are <u>assumptions</u> that may be changed by advanced users**

Rate Design Options

Menu:
- Full Retail Rate Credit
- Cost-based Comp
- Value-based Comp
- Retail Rate Credit+ Value-based Export Comp

- **Default residential energy rate structure options:**
  - Tiered/Inclining block (2,3, or 4 tiers)
    - Potential tier cutoffs at 100% of current baseline, 130% of baseline, and 200% of baseline (users can only flatten the existing tiers)
  - Time-of-use (TOU)
    - User can specify each of 8 summer and 8 winter weekday time intervals as on-peak, mid-peak, or off-peak
      - Intervals: 6am-9am, 9am-12pm, 12pm-2pm, 2pm-4pm, 4pm-6pm, 6pm-8pm, 8pm-10pm, 10pm-6am (ex. on-peak periods are 2pm-4pm in winter and 4pm-8pm in summer)
      - Weekends are constrained to be modeled as off-peak
  - Seasonal TOU + baseline credit for monthly usage up to baseline
  - Flat (non-TOU, non-tiered)
- **Users also specify a CARE % discount**

TOU Definitions

Menu:
- Full Retail Rate Credit
- Cost-based Comp
- Value-based Comp
- Retail Rate Credit+ Value-based Export Comp

+ **Examples of valid Public Tool TOU period definitions:**

		Example #1		Example #2	
Hour Beginning	Hour Ending	Summer TOU	Winter TOU	Summer TOU	Winter TOU
0:00	1:00	Off Peak	Off Peak	Off Peak	Off Peak
1:00	2:00	Off Peak	Off Peak	Off Peak	Off Peak
2:00	3:00	Off Peak	Off Peak	Off Peak	Off Peak
3:00	4:00	Off Peak	Off Peak	Off Peak	Off Peak
4:00	5:00	Off Peak	Off Peak	Off Peak	Off Peak
5:00	6:00	Off Peak	Off Peak	Off Peak	Off Peak
6:00	7:00	Off Peak	Off Peak	Mid Peak	Mid Peak
7:00	8:00	Off Peak	Off Peak	Mid Peak	Mid Peak
8:00	9:00	Off Peak	Off Peak	Mid Peak	Mid Peak
9:00	10:00	Mid Peak	Off Peak	Off Peak	Off Peak
10:00	11:00	Mid Peak	Off Peak	Off Peak	Off Peak
11:00	12:00	Mid Peak	Off Peak	Off Peak	Off Peak
12:00	13:00	Mid Peak	Mid Peak	Off Peak	Off Peak
13:00	14:00	Mid Peak	Mid Peak	Off Peak	Off Peak
14:00	15:00	On Peak	Mid Peak	Mid Peak	Off Peak
15:00	16:00	On Peak	Mid Peak	Mid Peak	Off Peak
16:00	17:00	On Peak	Mid Peak	On Peak	Mid Peak
17:00	18:00	On Peak	Mid Peak	On Peak	Mid Peak
18:00	19:00	Mid Peak	On Peak	On Peak	Mid Peak
19:00	20:00	Mid Peak	On Peak	On Peak	Mid Peak
20:00	21:00	Off Peak	Mid Peak	Mid Peak	Mid Peak
21:00	22:00	Off Peak	Mid Peak	Mid Peak	Mid Peak
22:00	23:00	Off Peak	Off Peak	Off Peak	Off Peak
23:00	24:00	Off Peak	Off Peak	Off Peak	Off Peak

+ **Users have a lot of flexibility in defining TOU periods**
  - Allows for afternoon on-peak periods and evening on-peak periods
  - Can approximate all proposed TOU definitions within an hour
+ **User may also choose to have the Public Tool pick define TOU periods internally**
  - May change over time to reflect the changing net load shape

NEM Alternative Rate Design Options

Menu:
- ★ Full Retail Rate Credit
- Cost-based Comp
- Value-based Comp
- Retail Rate Credit+ Value-based Export Comp

+ **Recall that NEM successor tariffs for customers who install DER post-2016 can differ from the default retail rates**
+ **NEM successor retail rate designs may include any rate design components available for default rates**
  - Actual chosen rate design may differ (ex. tiered rate for default residential customers and TOU rate for residential NEM successor tariff)
+ **Additional rate design components available for NEM successor rate design (for all customer segments):**
  - Residential monthly maximum demand charge ($/kW net usage)
  - Grid charge ($/kW nameplate capacity)
  - Grid charges by TOU period
    - $/kWh generated or $/kWh net usage
  - Non-residential standby charges ($/kW nameplate capacity)
  - Non-bypassable and delivery charges on $/kWh exported or $/kW nameplate capacity
    - Nameplate capacity approximates all generation kWh
    - Additional to non-bypassable and delivery charges applied to net usage
    - Prevents DER customers from avoiding non-bypassable charges

NEM Alternative Rate Design Options

- **Alternatively, users may test a cost-causation rate in place of the NEM successor tariffs**
- **Cost-causation rate reflects marginal $/kWh and $/kW costs by customer segment and collects embedded costs**
  - Designed internally within the model
  - Designed based on the definition of cost-of-service so that there cannot be a cost shift
  - Provides a corner point when balancing any cost impact
- **Cost-causation rate components**
  - Marginal energy cost by time period
  - Coincident peak demand charge
  - Non-coincident peak demand charge
  - Fixed charge per month

Levels of these charges are developed to be consistent with the cost of service allocation methodology

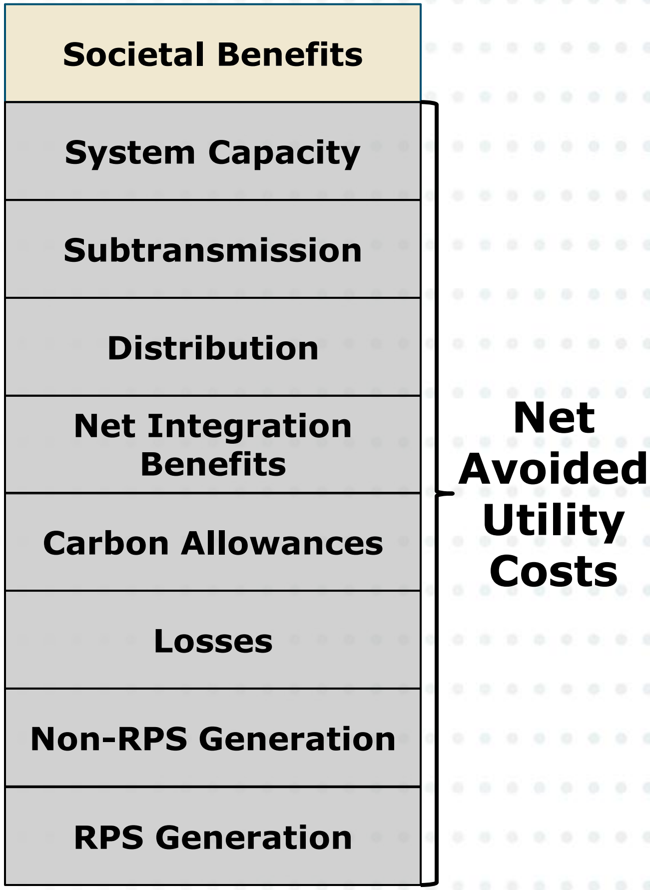
Cost-based Compensation

- **Cost-based Comp is one $/kWh payment (by tech) that aims to compensate a representative DER system just enough to recover costs**
  - Because DER systems vary in cost and performance, this will overcompensate some participants and undercompensate others
- **User defines the characteristics of the representative DER system**
  - Public Tool then calculates the $/kWh Cost-based Comp by DER technology
- **$/kWh payments may be flat, inclining, or declining over time**
  - All structures will collect the same revenue on an NPV basis
- **Tariff requires a separate meter**

Value-based Compensation

- **Value- or market-based compensation mechanisms aim to compensate DER based on part or all of its net value**
  - Value can be defined as societal value or value to the grid
- **Perfect and complete grid value-based compensation would have no rate impacts**
- **$/kWh Compensation level can include <u>any or all</u> of the following values:**
  - Market energy avoided costs, (including losses and carbon costs)
  - Avoided RPS generation adder
  - Ancillary service benefits less integration costs ("net integration benefits")
  - Any or all of the other avoided cost components (distribution, subtransmission, system capacity)
  - Societal externality benefits (ex. health)
- **$/kWh payments may vary by TOU period**

Example Value-based Compensation



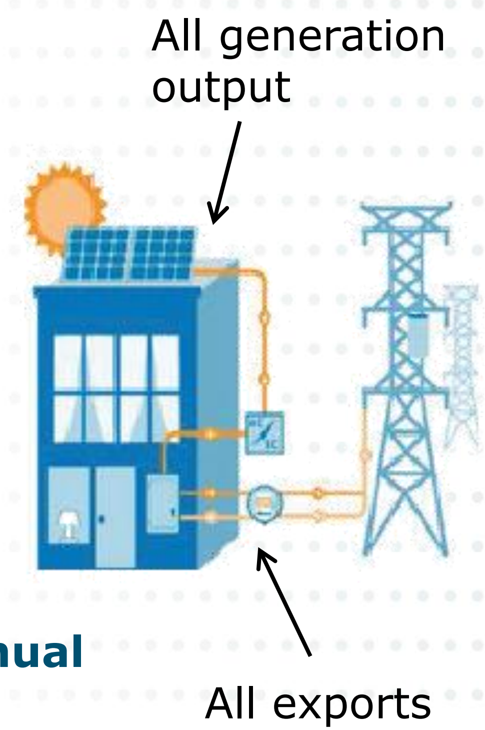
Tax and Regulatory Considerations

Menu:
- Full Retail Rate Credit
- Cost-based Comp
- Value-based Comp
- Retail Rate Credit+ Value-based Export Comp

- **Investment Tax Credit: User can select whether or not Cost- and Value-based Compensation receives the ITC**
- **Taxation: User can select whether or not Cost- and Value-based Compensation is taxable**
- **Regulatory updates: Users can determine how frequently these tariffs are updated**
  - Updates adjust for changes in utility/societal value and correct for cost uncertainty

Retail Rate Credit + Value-based Export Comp

- **On an annual basis, behind-the-meter output consists of:**
  1. Generation consumed on customer's premise
  2. Generation exported that is later consumed
  3. Surplus generation exported
- **This asymmetrical rate compensates generation consumed on premise (#1) at the retail rate level and provides value-based compensation for exported generation (#2)**
- **The Public Tool assumes regulation prevents annual DER from being greater than annual usage**
  - So the model does not model net surplus compensation (#3)
- **Netting: The Public Tool calculates net exports on a half-hourly basis**
- **All Retail Rate Credit options and Value-based Comp options apply to the respective parts of the asymmetrical rate**



Questions

Other
4:00 pm – 4:15 pm

Overview of Proposed Approach
Questions 1-2

Modeling Approach
Questions 3-9

Data Sources
Questions 10-11

Public Tool
Questions 12-20

Pricing Mechanisms and Rate Design
Questions 21 - 27

Other Issues
Question 29

Questions

Energy+Environmental Economics

Thank You!

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